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Siting Potential for Coal Gasification Plants in the United States

UNITED STATES DEPARTMENT OF THE INTERIOR

Information Circular 8735

Siting Potential for Coal Gasification Plants in the United States

By A. E. Lindquist

UNITED STATES DEPARTMENT OF THE INTERIOR
Cecil D. Andrus, Secretary

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SITING POTENTIAL FOR COAL GASIFICATION PLANTS IN THE UNITED STATES

by

A. E. Lindquist[1]

ABSTRACT

This Bureau of Mines publication identifies areas having sufficient coal reserves to support synthetic natural gas (SNG) development and summarizes those areas having the highest potential. Capital requirements, mining and coal cost factors, water availability, and coal-quality data pertinent to SNG production are presented. Evaluation of individual coal reserve blocks was based upon coal and water requirements of the Bureau of Mines Synthane coal gasification process.

INTRODUCTION

The availability of natural gas is on a decline in the United States. The Federal Bureau of Mines has projected that demand for natural gas imports could exceed 2.5 trillion cubic feet annually by the year 2000 (13).[2] Other sources of energy must be developed as a substitute for natural gas, which constituted about 27 percent of U.S. total energy usage in 1976. Synthetic natural gas (SNG) derived from coal is one method of augmenting natural gas supplies, perhaps the most viable method available at the present time.

The extent to which SNG gains importance in the domestic energy-supply mix is dependent upon many factors, including environmental and coal mining legislation, natural gas supply, petroleum (including liquefied natural gas) import policies, and the ability of the industry to secure the large amounts of capital necessary to finance a gasification industry.

The Federal Power Commission (FPC) sets rate structures for the interstate sale of natural gas. The FPC has ruled that it has no authority to regulate the gas produced from coal until such SNG is mixed with natural gas in the pipeline, at which point its higher cost is to be taken into account in the rate structure (28). The last feature could allow some assurance of capital recovery.

---

[1]Mining engineer, Intermountain Field Operations Center, Denver, Colo.

[2]Underlined numbers in parentheses refer to items in the bibliography preceding the appendix.

Coal gasification processes currently being evaluated at the pilot plant stage may be termed second-generation processes and should be ready for commercialization sometime after 1980 (9, 18).

Some foresighted individuals envision "coalplexes," conceivably the third generation of coal conversion processes (9). Such highly elaborate plants could produce syncrude, SNG, synthetic fuel gas, electricity, fertilizer, chemical byproducts, and low-sulfur coke. Excess heat could be used for agriculture and fish hatcheries.

The Bureau of Mines was concerned for many years with developing coal conversion processes to produce synthetic gaseous and liquid fuels from coal. In January 1975 the six Bureau of Mines Energy Research Centers were transferred to the Energy Research and Development Administration (ERDA).

The United States has an ample coal reserve base to support an extensive SNG industry. It is the purpose of this report to delineate areas where sufficient coal is available and to outline some of the other requirements and problems associated with synthetic gas development.

Previous publications dealing with the subject of SNG have dealt primarily with the technology and economics of coal-gas conversion processes, analyzed the need for supplemental gas sources, projected possible levels of development, and dealt with the financial aspects of synthetic gas development. Those studies that dealt with coal reserves-site selections were not based on data from the Bureau of Mines comprehensive Fuels Availability System. The use of data from this system, which contains reserve base information by sulfur content, allowed elimination of low-sulfur eastern coal suitable for use in coal-fired generating plants from consideration as gasification feedstock.

ACKNOWLEDGMENTS

Preliminary data on the coal reserve base and coal gasification processes were gathered by T. K. Matson, physical scientist; P. A. Hamilton, minerals economist; and D. H. White, Jr., supervisory physical scientist, Intermountain Field Operations Center, Denver, Colo. In addition, T. K. Matson prepared the sections on gasification history and processes. R. J. Bielicki, physical scientist, Eastern Field Operation Center, and R. E. Smith, now with Pittsburgh Technical Support Center, Mining Enforcement and Safety Administration, formerly Eastern Field Operation Center, Pittsburgh, Pa., prepared initial data on potential gasification areas in the Eastern United States. Data on the requirements, performance, and economics of the Federal Bureau of Mines Synthane gasification process now under further development in ERDA were supplied by K. D. Plants, chemical engineer, and Sidney Katell, chief (now retired), Process Evaluation Group, Morgantown, W. Va.

DEFINITIONS

Certain terms and abbreviations frequently used in this report are defined herewith:

Synthetic natural gas (SNG).--Manufactured gas compatible with natural gas as transported in a pipeline. The artificial gas will contain approximately 90 percent methane and have a heating value greater than 900 Btu per standard cubic foot (scf).

Gasification.--In the context of this report, the conversion of coal to a combustible gas known generally as artificial, synthetic, or manufactured gas.

Basic SNG plant.--A synthetic natural gas plant that produces approximately 250 million standard cubic feet per day (MMscfd).

HISTORY

The conversion of coal into gas is not a recent phenomenon. Manufactured gas was used for illumination in England in 1802 and in the United States in 1813. Illumination was the principal use for gas produced from coal until the 1900's, when it began to be used in the residential cooking and heating markets. As late as 1932, manufactured gas was the major supplier to the eastern residential gas market.

The discovery of vast natural gasfields and the subsequent development of pipeline transmission technology effectively ended the use of manufactured gas in the United States shortly after World War II.

Domestic research into coal conversion technology has been rather limited since the decline of the domestic manufactured-gas industry earlier in the century. Sufficiently large reserves of low-cost energy were available to render the economics of coal conversion unattractive.

The Federal Bureau of Mines has been active in research for the conversion of coal to synthetic fuels since the mid-1930's. However, funding was not adequate for large-scale research and development until recently (28, 30). The Office of Coal Research (OCR) (28-29), established in 1960, was directed to develop new and better uses for coal. Most of the early efforts of OCR were aimed at liquefaction because of economics--cheap supplies of natural gas. In 1971 OCR and the American Gas Association, active in coal research the last 10 to 15 years, cooperated in a program of coal gasification research and development (30). Because the U.S. domestic energy-supply situation was becoming untenable, OCR was reorganized and expanded in 1972 with increased funding, and was incorporated into the Energy Research and Development Administration (ERDA) in January 1975. The Bureau of Mines energy research arm was also incorporated into ERDA.

Recent tightening of the domestic natural gas supply has spurred new efforts to develop viable methods of converting coal to SNG. Over the last

5 years a number of processes have evolved to the pilot plant stage through concentrated effort by Government and industry.

Until recently, when major natural gas discoveries were made in the Netherlands, the North Sea, and the U.S.S.R., Europe has been without adequate supplies of natural gas. Coal conversion, as a result, has been more important there. In 1936, the initial Lurgi process to convert coal to gas was developed in Germany and has undergone continual refinement since.

In spite of recent domestic developments in coal conversion technology, the first commercial coal conversion complexes for SNG manufacture in the United States probably will utilize the Lurgi process. The capital investment required for such commercial-scale plants is enormous; therefore, the first-generation plants are expected to employ this proven European technology for producing synthesis gas in conjunction with newly proven technology for upgrading methanation of this synthesis gas (300 to 500 Btu/scf) to SNG. The latter step, purification and catalytic methanation, only recently was commercially proven during yearlong tests conducted at the Scottish Gas Board's synthesis gas plant at Westfield, Scotland. The gas produced was consumed in Fife, Scotland (5-6, 36).

A variety of problems confronts the SNG industry. Principal deterrents cited by industry are as follows: Rapidly escalating capital requirements, inability to gain approval or guarantee of gas rates at a level sufficient to attract the necessary capital, lack of a firm Government energy policy, opposition by groups opposed to development of the industry, uncertainties as to the cost of coal feedstock, and the inability to obtain the many permits required.

Several industry spokesmen have recently advanced the concept that Government participation is necessary if the SNG industry is to become viable. Assistance would be in the form of direct capital participation or a guaranteed gas rate policy.

The aforementioned problems have delayed initiation of some projects and forced cancellation of others. In early 1977, the commercial-scale SNG projects nearest actual construction were in North Dakota and New Mexico. In North Dakota two complexes are in the active, preconstruction phases. American Natural Gas Co. is continuing detailed engineering studies on its Mercer County, N. Dak., plant. North American Coal Co. will supply the lignite feedstock. Water permits have been granted for the first 250-MMscfd phase of the project. Current plans are to construct a scaled-down 125-MMscfd facility to be completed by midyear 1981.

The Natural Gas Pipeline Co. of America is engaged in the initial engineering and environmental study stage for a proposed SNG facility in Dunn County, N. Dak. Preliminary plans project construction of a 250-MMscfd plant to go on line in 1982, with additional equal components to be added at three 5-year intervals to attain an ultimate capacity of 1,000 MMscfd.

In New Mexico's San Juan County, the Western Gasification Co. (WESCO) plans to produce 250 MMscfd with ultimate expansion to 1,000 MMscfd, although plans have been delayed indefinitely. A second complex had been considered in this same area by El Paso Natural Gas Co., but the decision to proceed further has been deferred. Proposals for SNG plants have also been announced or advanced for locations in Kentucky, Pennsylvania, Illinois, Colorado, Wyoming, and Montana, but none is presently as advanced as the three projects cited.

GASIFICATION PROCESS

Chemical reactions in the conversion of coal to gas are the same in modern gasification processes as they were in earlier methods. However, research and development, particularly intensive over the last 10 years or so, have brought about significant advances in process design. Greater efficiencies and improved product gases are now attainable. These advanced designs have resulted in conversion schemes that allow the production of SNG rather than lower Btu gases.

Modern Methods of Obtaining Gas From Coal

Three types of manufactured gas are being considered for production: Low-, intermediate-, and high-Btu. Low-Btu synthetic-fuel gas has an approximate heating value of 100 to 250 Btu/scf. This gas is best used near its source of manufacture for electric-power generation or other industrial application--this use would take advantage of the sensible heat in the hot gas. Also, the low-Btu value and compression costs make the economics of transmitting this gas over any distance unattractive. Intermediate-Btu gas, using oxygen in the gasification phase, has an approximate heating value of 300 to 500 Btu/scf. This synthesis gas, containing primarily hydrogen and carbon monoxide, would be suitable for some direct industrial applications or for upgrading to a high-Btu or SNG. To be compatible with natural gas, this high-Btu SNG must contain approximately 90 percent methane with a heating value greater than 900 Btu/scf. The upgrading of this intermediate-Btu, or synthesis gas, to high-Btu SNG is covered in the following discussions.

Major Phases in the Modern Gasification Process

Five essential phases are common to the production of SNG from coal: Coal preparation and pretreatment, gasification, shift conversion, gas purification, and methanation (35). A sixth stage, compression, may be necessary to raise the product gas to pipeline-transmission pressure. The various processes developed for SNG production differ in the design and operation of these phases.

Coal Preparation and Pretreatment

All processes for manufacturing SNG require some degree of coal preparation before gasification. The run-of-mine coal must meet process requirements for particle size and may have to meet criteria for chemical composition. Preparation usually involves breaking the raw coal, washing, crushing, screening, and drying.

Coal pretreatment involves the destruction of coal-caking properties while retaining as much of the volatile matter as possible (33). The destruction of coal-caking properties is particularly important when a fixed-bed process is used where agglomeration of coal particles cannot be tolerated (15).

Gasification

The atomic ratio of hydrogen to carbon is less than 1:1 for coal, whereas this ratio is 4:1 for methane. Therefore, converting coal to SNG necessitates the addition of hydrogen, the removal of carbon, or both (1, 50). Consequently, gasification by any process must either convert the coal directly to methane or provide a synthesis gas capable of being upgraded to methane-rich gas through further processing.

Gas is obtained from coal by these primary methods: Pyrolysis, hydrogasification, and synthesis gas methanation (35-36). The methods are not mutually exclusive; products or steps of one method can and have been combined with those of another to produce SNG.

Pyrolysis involves the heating of coal in the absence of air or oxygen. A portion of the volatile hydrogen combines with carbon to form methane. The hydrogen-carbon ratio results in a large part of the coal emerging as byproduct char, which also can be gasified (35).

In hydrogasification, hydrogen from an external source is reacted with the carbon in coal or char to form methane according to the reaction

$$C + 2H_2 = CH_4 \quad (15, 33, 35).$$

The less reactive portion of the coal or char is usually used to produce hydrogen (21). For this process to be economical, this external source of hydrogen must be inexpensive.

The third gasification method, synthesis gas production, results in an intermediate-Btu gas, which requires further treatment to upgrade it to a methane-rich SNG. In this method, steam and either air or oxygen are reacted with the carbon in the coal. Because essentially all modern processes use oxygen to prevent nitrogen dilution of the product gas, an inexpensive supply of oxygen is necessary. The carbon-steam reaction is highly endothermic; thus heat must be supplied to the gasifier by a heat carrier, by partial combustion of the coal with oxygen, or by an externally applied heat source (33). The synthesis gas produced contains mainly hydrogen and carbon monoxide. The primary reaction in synthesis gas production is the following:

$$C + H_2O = H_2 + CO \quad (33, 35).$$

Many of the processes being considered use some combination of the gasification methods described. Physical differences among processes usually involve the use of fixed-bed, fluidized-bed, or suspension-type gasifiers (15).

Shift Conversion

The major components of shift conversion, which requires a large amount of steam, are the waste-heat boiler where the effluent from the gasifier is cooled, the reactor vessel, and the product-gas cooler. The effluent from the gasifier must be processed to achieve the proper hydrogen-to-carbon monoxide ratio for attaining methanation. This ratio is adjusted to approximately 3:1 in the shift converter via the water-gas shift reaction:

$$H_2O + CO = H_2 + CO_2 \quad (33, 41, 50).$$

Gas Purification

Purification removes vapor-phase impurities from the gas stream to meet standards of pipeline gas and to condition the gas for attaining methanation. Carbon dioxide, a diluent that lowers heating value, is removed by scrubbing. Toxic sulfur compounds must be removed to prevent contamination of the nickel catalysts usually used in the methanator. The primary methods of gas purification are absorption into a liquid, chemical conversion to another compound, and adsorption onto a solid (35). These methods are often combined to obtain the desired gas purity.

Methanation

Methanation entails the catalytic conversion of excess hydrogen and carbon monoxide into methane via the reaction

$$CO + 3H_2 = CH_4 + H_2O \quad (21, 33).$$

Because this reaction is highly exothermic, heat exchangers are required to control the temperature.

Process Descriptions

Much of the technical and economic data included in this report are based on the Bureau of Mines Synthane process, now under further development in ERDA, while commercial SNG plants presently planned will use the Lurgi pressure-gasification process. Therefore, brief descriptions of these processes are included.

Synthane Process

The Bureau of Mines has developed a process design using fluidized-bed gasification followed by shift conversion, purification, and single-stage methanation. A brief description of the process as detailed in reports from the Federal Bureau of Mines Process Evaluation Group follows, including a simplified process flow diagram as shown in figure 1.

Run-of-mine coal is reduced to minus three-fourths of an inch and stockpiled. Coal from the stockpile is pulverized to 70 percent through 200 mesh and fed to the gasifier by lock hoppers. The gasifier operates at 1,000 psia

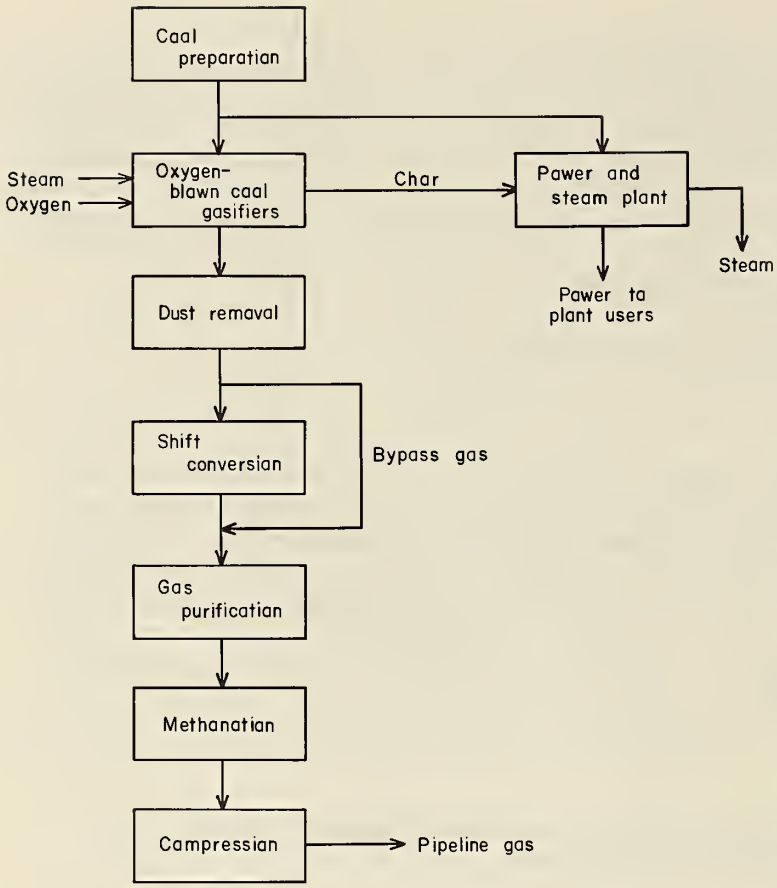

FIGURE 1. - Synthane process simplified flow diagram.

at a maximum of 2,000° F. Coal pretreatment, for the destruction of caking properties, is accomplished at the top of the gasifier where heated steam and oxygen partially devolatilize the coal. Steam and oxygen are also fed to the bottom of the gasifier.

Entrained dust in the gas leaving the gasifiers is removed in cyclone separators and tars are removed by water scrubbing. The gas stream is then split into two equal streams. One stream bypasses the shift converters; the other stream is preheated by heat exchange with the product gas before entering the converters. Catalytic conversion of this second stream produces the desired H_2:CO ratio. This gas is then cooled by heat exchange with the feed gas and is recombined with the bypass stream and further cooled in a heat recovery system.

In the purification stage, the gas is further cooled in the regenerator reboiler and a water cooler before entering the absorbers where hot potassium carbonate solution is used to remove carbon dioxide, hydrogen sulfide, and carbonyl sulfide. The exit gas is then cooled and routed through iron oxide and char towers for residual-sulfur cleanup.

Feed plus recycle gas is heated, by heat exchange with the product gas from the methanation stage, before upgrading by reacting the hydrogen and carbon monoxide to form methane and water.

The cooled product gas is then compressed to 1,000 psig for pipeline transmission. Containing about 90 percent methane, the gas has a heating value of over 900 Btu/scf.

The Synthane process design is based upon some data extrapolated from laboratory test results. Further experimental work on the gasification and methanation steps is indicated to verify assumptions made to facilitate the evaluation stages.

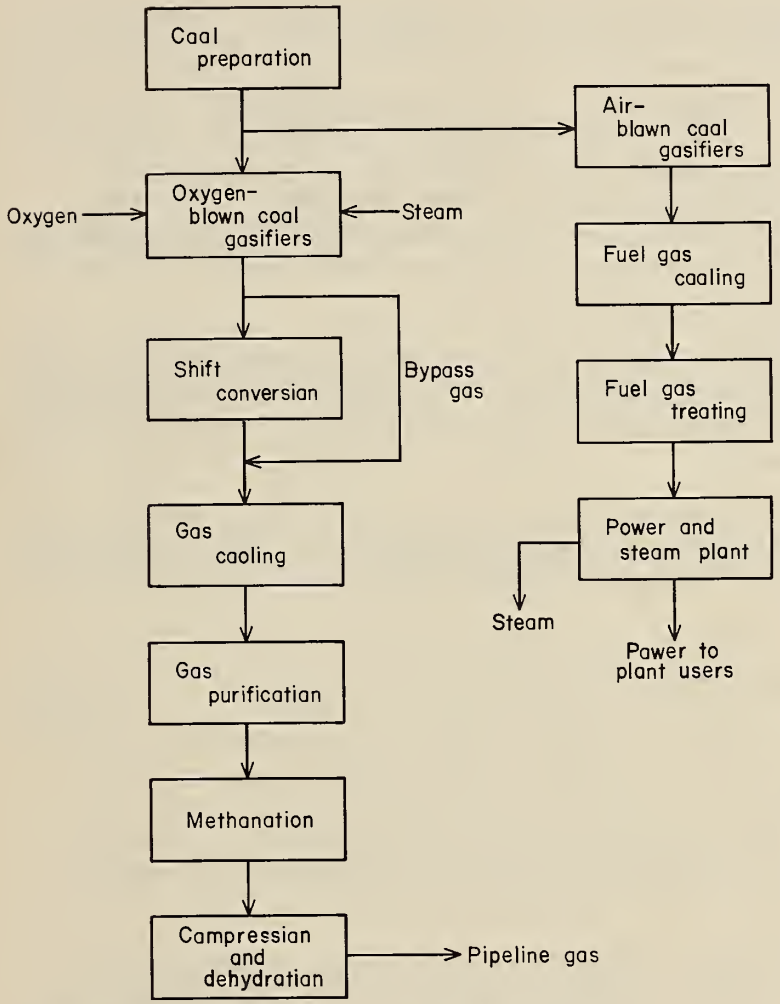

FIGURE 2. - Lurgi process simplified flow diagram.

Lurgi Process

The Lurgi process is the only commercially proved coal gasification process; the first plant was built in 1936 in Zitlan, Germany (28). The methanation step has been successfully demonstrated. The following description is based upon process design for the El Paso Natural Gas Co. complex (5-6). A simplified process flow diagram is shown in figure 2.

Run-of-mine coal is crushed to minus 1-3/4 inch and stockpiled. This coal is then screened and 3/16- by 1-3/4-inch coal is fed to the gasifiers. The coal enters the gasifier through a coal lock chamber and is reacted with oxygen and steam in a slowly moving bed at pressures up to 450 psig. The gasifier consists of essentially three zones: The coal-preheat and devolatilization zone, the gasification zone, and the combustion zone.

The raw gas from the gasifier is fed to the washer cooler where it is rapidly cooled and dust scrubbed out by quenching with a gas liquor spray. This gas is further cooled in the waste-heat boilers and split into two equal streams, one going to shift conversion and the other bypassing shift conversion and going directly to the gas-cooling unit.

Shift conversion consists of two parallel catalytic reactors where carbon monoxide and water are converted to hydrogen and carbon dioxide by the "water-gas shift" reaction. The gas entering this unit is first cooled to condense heavy hydrocarbons and then heated by heat exchange with product gas, which, in turn, is cooled by the feed gas.

The product gas then enters the gas-cooling unit where it passes through a process waste-heat boiler, a boiler feedwater preheater, an air cooler, and a gas cooler. The gas that bypassed shift conversion enters the gas cooler and passes through a process waste-heat boiler, a low-pressure steam generator,

an air cooler, and a water cooler before being recombined with the parallel gas stream before purification.

Gas purification is by the proprietary Lurgi Rectisol process using methanol at a low temperature to remove selectively carbon dioxide and gum-forming compounds; recover crude naphtha; and reduce the concentration of hydrogen sulfide, carbonyl sulfide, and other sulfur compounds. The inlet gas is cooled and sent to the prewash tower where cold methanol removes water and naphtha, thence to the main absorber where further reduction of sulfur compounds is accomplished by another methanol wash.

Following purification, the synthesis gas is reheated and passed through two stages of reactors for catalytic conversion of hydrogen and carbon monoxide to form methane and water. The upgraded gas is then passed through condensate separators to remove water.

Gas from the methanation unit is compressed to 1,000 psig in a multistage centrifugal compressor, cooled, and then dehydrated before pipeline transmission. The product gas contains about 90 percent methane and more than 900 Btu/scf.

ENVIRONMENTAL CONSIDERATIONS

Mining and gasification of coal will exert some changes on the environment. Some potential problems associated with underground mining in the interior and Eastern United States are acid mine-water drainage, expelling degraded mine-ventilation air into the atmosphere, land subsidence, mine fires (occasionally resulting in subsidence and gaseous emissions), and the disturbance of ground- and surface-waterflows and levels.

Potential environmental effects associated with surface mining are disturbance of natural animal and vegetal life in the mined area; withdrawal of the land from agricultural or other uses during mining; possible destruction of ground- and surface-waterflows and levels; air pollution from dust; noise pollution from blasting; a restored topography that, except in unusual situations, will not be at the same elevation or of the same configuration as the original; and the degree of success of reclamation efforts.

The primary environmental considerations involved in commercial-scale coal gasification will be mine reclamation and air pollution, with mine reclamation probably being of greater concern.

The deciding factor in reclaiming strip-mined lands must be the establishment of final use following mining operations. Reclamation procedures will vary depending upon future land use, such as recreation versus agriculture. Reclamation involves grading spoil piles to prescribed contours, burying acid-forming materials with a cover of overburden, controlling contaminant discharge, storing and replacing topsoil, constructing necessary dams, and revegetating.

Commercial-scale coal gasification will involve reclaiming large areas of disturbed land. For example, to supply a 250-MMscfd SNG plant, a mine producing 8,500-Btu/lb coal from a 20-foot seam with 80 percent recovery would disturb approximately 285 acres of land per year. For a plant with a 35-year life, 9,975 surface acres would be mined.

Generally, the more spoil material moved, the greater the cost of reclamation. Likewise, geologic, geographic, and climatic conditions will affect reclamation costs.

Primary soil conditions affecting the success of reclamation are the percentage of hard rock or shale in the overburden; the amount of sulfides or other materials in the rock or shale that are toxic to plant growth; the distribution of soil-size particles; and the amount of lime, phosphate, and potash available for plant growth.

Revegetation will be the greatest problem in mined-land restoration in the West. There is a limited amount of moisture in the Western States; some areas in New Mexico and Arizona are classified as desert.

Potential environmental effects associated with a gasification plant are loss of plantsite land for other uses; disturbance of natural animal and vegetal life; thermal pollution; and release of sulfur dioxide, nitrogen oxides, carbon dioxide, and particulate matter into the atmosphere.

OPERATING AND ECONOMIC CONSIDERATIONS

The conversion of coal to pipeline-quality gas will require substantial capital outlays, both for the mining operation and the gasification facilities.

As presented in this report, capital investment and operating costs for coal mines or SNG plants refer to general rather than specific situations (location, coalbeds, structure, etc.).

The capital investment and operating costs determine the base rate at which manufactured gas can be sold at the plantsite. In these operating costs, the cost of coal is the single most important factor. Estimates made on the Synthane SNG process by the Bureau of Mines Process Evaluation Group also indicate that the quality (Btu content) of coal significantly affects the capital investment necessary to bring a plant on line.

Cost analyses on two underground and three surface operations designed to produce coal in sufficient quantities for SNG feedstock are summarized in table 1. Costs are based on 1975 prices.

During 1972-73, the Bureau of Mines Process Evaluation Group performed seven cost analyses of the Synthane coal gasification process; in the analyses, coals of different price and characteristics were used to produce 250-MMscfd SNG. Analyses were based on a 330-day operating year and allowed credit for byproducts. Annual operating costs varying with the cost of the coal are shown in table 2. Costs shown are on a 1975 base.

TABLE 1. - Summary cost data on hypothetical mines supplying SNG feedstock

	Eastern province (Appalachia)	Eastern Interior province		Northern Great Plains province	
State	Undefined	Undefined	Illinois	Montana	Wyoming
Coal rank	Bituminous	Bituminous	Bituminous	Subbituminous	Subbituminous
Type operation[1]	Underground	Underground	Surface	Surface	Surface
Coal thickness, feet	6	6	3.4	57	([2])
Maximum overburden, do	-	-	150	120	120
Annual tonnage, million tons	4.73	6.58	6.72	9.20	9.05
Initial capital investment, millions	$95.65	$92.16	$195.44	$41.70	$53.35
Deferred capital expenditure, do	$29.82	$38.64	$20.22	$27.13	$30.39
Total capital expenditure, do	$125.47	$130.80	$215.66	$48.83	$83.74
Production costs, per ton	$7.38	$6.09	$4.42	$2.60	$3.41
Selling price, per ton[3]	$11.66	$8.94	$10.58	$3.40	$4.29

[1]Each operation consists of two mines.
[2]Two seams--upper coal thickness 29 feet, lower coal thickness 20 feet.
[3]15 percent DCF rate of return.

NOTE.--Costs are based on January 1975 indexes.

Source: Federal Bureau of Mines, Process Evaluation Group.

TABLE 2. - Comparison of Synthane process costs on different coals

Coal costs per ton	Annual operating costs based on coal costs, millions						
	Pittsburgh coalbed	Illinois No. 6 coalbed	Rock Springs coalbed	Shiprock coalbed	Rosebud coalbed	Montana subbituminous coalbed	Lignite coalbed
Btu/lb (at gasifier)	13,403	12,000	13,167	12,485	8,661	10,755	7,088
$5	-	-	$87.21	$91.25	$121.15	$88.75	$120.28
7	-	-	97.32	102.08	137.73	96.81	139.43
9	-	-	107.43	112.91	154.32	104.87	158.58
11	$118.97	$139.74	-	-	-	-	-
13	128.39	151.56	-	-	-	-	-
15	137.81	163.37	-	-	-	-	-
	Gas selling price at plant based on coal costs per Mscf[1]						
	Pittsburgh coalbed	Illinois No. 6 coalbed	Rock Springs coalbed	Shiprock coalbed	Rosebud coalbed	Montana subbituminous coalbed	Lignite coalbed
Btu/lb (at gasifier)	13,403	12,000	13,167	12,485	8,661	10,755	7,088
$5	-	-	$2.27	$2.36	$3.02	$2.94	$2.86
7	-	-	2.39	2.49	3.22	3.06	3.09
9	-	-	2.51	2.62	3.42	3.16	3.32
11	$2.85	$3.07	-	-	-	-	-
13	2.96	3.21	-	-	-	-	-
15	3.08	3.35	-	-	-	-	-

[1]15 percent DCF rate of return.

NOTE.--Costs are based on January 1975 indexes.

Source: Federal Bureau of Mines, Process Evaluation Group.

Early 1975 Lurgi process gas costs for presently planned or projected projects were between $2.40 and $3.00 per thousand scf (Mscf) SNG (7).

A commercial-scale SNG gas complex has not been built in the United States; thus proved technical data upon which to form a cost base are unavailable.

Using different coals, the Federal Bureau of Mines Process Evaluation Group has made several estimates of the Synthane SNG process requirements. Table 3 is a compilation of some of the information contained in these studies and indicates the general range of coal, water, and manpower necessary to operate a basic SNG plant.

TABLE 3. - Synthane SNG plant requirements

(Basic plant = 250 MMscfd)

	Coalbeds					
	Lignite	Rock Springs	Shiprock	Montana Rosebud	Pitts-burgh	Illinois No. 6
Coal.....Btu/lb..	7,088	13,167	12,485	8,661	13,403	12,000
Direct employment.....	788	685	699	840	758	751
Water acre-feet per year..	27,700	29,200	29,200	35,000	26,250	32,100
Annual coal million tons..	9.57	5.06	5.41	8.29	4.70	5.91
Total coal in 35 years.....million tons..	335	177	189	290	165	207
Annual operating cost.....millions..	[1] $139.43	[1] $97.32	[1] $102.08	[1] $137.73	[2] $128.39	[2] $142.45
Total capital investment[3].....millions..	$521.78	$449.33	$461.38	$571.21	$514.06	$503.50

[1] $7.00 per ton of coal.
[2] $13.00 per ton of coal.
[3] Includes cost of construction of onsite electrical generation plant.

NOTE.--Costs are based on January 1975 indexes.

Source: Federal Bureau of Mines, Process Evaluation Group.

SNG projects currently projected and proposed will use the Lurgi process. Table 4 contains estimates made by industry as to the requirements for these plants. Plant locations and coals will be North Dakota lignite, New Mexico (Shiprock), and Wyoming (Wyodak) subbituminous. Initial plant capacities will be approximately 250 MMscfd. The data presented in the preceding tables serve as general summaries of SNG mine-plant requirements. However, the Btu content of the specific coal being considered largely determines the quantity to be mined as feedstock for a SNG plant.

TABLE 4. - Lurgi plant requirements

(Basic plant approximately 250 MMscfd)

	Coal	
	Lignite	New Mexico
Plant-size acreage	-	320-960
Direct employment	700-800	800-975
Water, thousand acre-feet per year	17-44	9.5
Annual coal, million tons	10	9.5
Total coal in 35 years, do	350	304
Capital investment[1], millions	[2]$600-$900	$735

[1]Includes cost of construction of an onsite electrical generation plant.
[2]January 1975 costs.

Capital investment estimates for the Synthane and Lurgi processes are included on tables 3 and 4; capital investment and operating costs, and thus coal and gas selling prices, are particularly tentative. As capital and operating costs continue to rapidly escalate, then so will the final SNG selling price. For example, in 1972 the cost of the Burnham complex in New Mexico was estimated at $400 million (14). In December 1973, the cost had escalated to $604 million (5), with only a small increase in the designed capacity; in December 1974, the estimated cost was nearly $700 million (48); and in June 1975, the cost was $1 billion (7). Initiation of construction on the project had been deferred.

BASIC CRITERIA AND PROCEDURE USED IN AREA SELECTION

In this report, a "basic SNG plant" is defined as one that produces 250 MMscfd of synthetic gas. This capacity has been judged to be the minimum size plant economically justifiable (51). The manufactured gas will have a heating value greater than 900 Btu/scf. Coal requirements, with an assumed conservative 55-percent thermal efficiency, will be 4.76×10^{15} Btu for a 35-year plant life.

Reserves are considered to be 85 percent of the strippable reserve base and 57 percent of the deep reserve base. Coal with less than 1.9 percent sulfur has not been considered for SNG use in the Eastern United States; such coal has a higher potential for use in thermal-electric generation and industrial applications. However, no such distinction was made for western coals.

Because of abundant strip reserves in the West, only strippable coal in this region has been considered for SNG development in the near future. The data were not ranked with respect to the number of coalbeds or the areal extent of dispersion of the beds. Furthermore, the reserves were not depleted to any future year based on actual production in a base year or statistical period.

The Bureau of Mines Fuels Availability System contains the coal-reserve base of the United States by State, county, nature of reserves (underground, strip), coalbed, and quality. As a means of selecting counties with

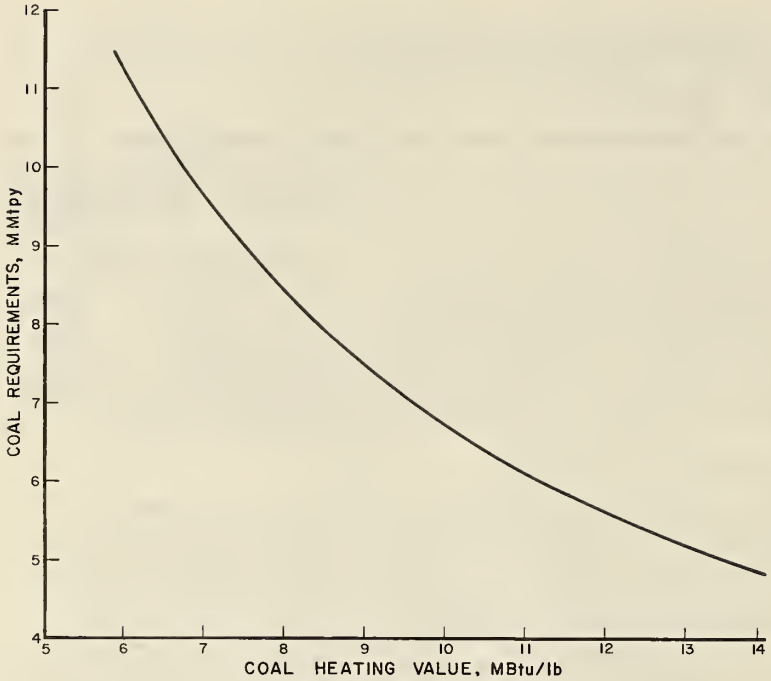

FIGURE 3. - Annual coal requirements for a 250-MMscfd Synthane process facility.

sufficient reserves to support a basic SNG plant, the reserve base of each county in the Fuels Availability System was converted to a reserve. The average Btu content of the coal in each county was applied to figure 3; the minimum reserve necessary over a 35-year period was then calculated. Those counties with a reserve above the 35-year minimum are noted and tabulated in the appendix.

COAL AVAILABILITY FOR GASIFICATION IN THE EASTERN UNITED STATES

Based solely on high-sulfur coal reserves and water availability, the potential for coal gasification plantsiting in the Eastern United States looks promising. The reasoning behind basing plantsiting potential on high-sulfur coal availability (1.9 percent sulfur or greater) is environmentally oriented. Coal of less than 1.9 percent sulfur content could be blended or otherwise cleaned to possibly attain the Environmental Protection Agency (EPA) primary air standards stipulated for coal consumption. Emissions from burning coal of high sulfur content must presently be cleaned by stack-gas scrubbing or related processes. These methods are expensive, and their effectiveness has been challenged in most situations. Because present stack-gas cleaners are not readily acceptable, owners and producers of high-sulfur coal are interested in developing new markets, such as coal gasification, for their product.

Outlook for a Coal Gasification Industry

A coal gasification industry could develop in the Eastern United States because of the indigenous supplies of water, availability of labor, and adequacy of coal reserves. The proximity of present gas-distribution systems and large consumer markets also provides a development incentive. Whether or not the industry could grow and be self-supporting, however, depends upon considerations other than water and coal reserves. Cost and availability of mined coal will be very important factors.

That the coal industry must expand production to meet the presently growing market demand is a certainty. Among the deterrents to this expansion are the following: A historically low annual rate of return on capital investment;

high initial capital investment for a large, new underground mine; 3- to 5-year development before commercial production from an underground mine can begin; possible equipment shortages and long lead times to delivery; governmental regulations affecting current as well as future operations; and labor and management problems. These and other factors, such as varied and uncertain surface-reclamation laws and regulations and potential disturbance of ecological systems, must be resolved before the industry can be expanded to meet even the present market needs. Detailed in earlier sections of this report are the parameters affecting gasification plantsiting, not the least of which is the type of coal mining required (surface or underground). Although availability of surface water is a siting problem in the West, availability of strippable coal is a problem in the East. Most potential gasification plants in the East would require the outputs of two or more captive underground mines for their coal supply. The cost factor that this entails for capital investment, operating costs, and coal transportation to the plantsite will be considerable. Because the cost of the product gas will be greatly affected by the cost of the coal, the eastern plantsiting dependency on underground mines must be given due consideration.

State Siting Potential in Eastern United States

Six States in the East contain enough high-sulfur coal reserves and available water to support a coal gasification industry. These are, in order of potential magnitude, Illinois, Ohio, West Virginia, Pennsylvania, eastern and western Kentucky, and Indiana. Illinois, Indiana, and western Kentucky are part of the Eastern Interior coal province; Ohio, Pennsylvania, West Virginia, and eastern Kentucky are in the Eastern coal province.

Counties with sufficient coal reserves for one basic SNG plant or more are listed in the appendix.

Illinois

Illinois, with more counties with high-sulfur coal reserves than any other State in the Eastern United States, has gasification plantsiting potential in 41 counties. Plants supported by deep mines could be constructed in 33 counties. Fourteen counties have strip mine potential; six could provide either type of mining operation. Fulton and Peoria Counties have the greatest potential for strip mine operations; Christian, Macoupin, Montgomery, and Sangamon Counties have the greatest potential for deep-mine supported sites.

A large coal mining industry is already present in Illinois, which produced an estimated 57.9 million tons in 1976. Another factor favoring gasification plantsiting here is a vast market for natural gas in the large population centers near the coalfields. For these reasons Illinois has a very high potential as a site for a coal gasification plant using high-sulfur coal.

Ohio

Sixteen counties in Ohio could support coal gasification plants. Four of these have strip mine potential and all 16 can support deep-mine operations. The area comprising Belmont, Harrison, and Jefferson Counties holds the greatest potential for plant locations in the State.

A large market for natural gas exists in the various population centers in Ohio. Ohio is one of the largest coal-producing States in the United States, with about 46.5 million tons of production in 1976. Such a large established coal industry and natural gas market tend to make Ohio a potentially good location for a synthetic-gas industry.

West Virginia

West Virginia is third in the East in the number of potential county plant locations. Fourteen counties, all with deep minable coal, could support gasification plants. Of these, Marion, Marshall, and Monongalia Counties hold the greatest potential.

The West Virginia mining industry, which produced an estimated 107.0 million tons in 1976, could probably increase its capacity to meet the demands of a gasification industry.

Pennsylvania

Pennsylvania has siting potential in 11 counties; all of the sites would be dependent on deep minable coal. The Greene-Washington County area, with the greatest potential in high-sulfur coal reserves, is also near a highly industrialized and heavily populated part of Pennsylvania, which could provide a market for the SNG product. Pennsylvania also has a well-established coal industry that produced about 83.4 million tons of bituminous coal and 6.2 million tons of anthracite in 1976. These factors would be conducive to a coal gasification industry.

Kentucky

Kentucky is divided into eastern and western regions. In eastern Kentucky, Pike County could support a coal gasification industry. Western Kentucky has seven counties with siting potential. Six could be supported by deep mines, and four, by strip mines. Three counties could use either or both types of mining. The output of the coal mining industry in Kentucky was about 140.2 million tons in 1976 and the industry should be capable of expanding to meet gasification plant needs.

Indiana

Eight counties in Indiana could supply coal gasification plants with high-sulfur coal for the projected plant lifetimes. All eight have deep coal reserves, whereas one, Warrick County, has strippable reserves of sufficient quantity. One of the largest industrial States, Indiana, produced about 24.4 million tons of coal in 1976.

In conclusion, the Eastern United States apparently has adequate markets, high-sulfur coal reserves, and the existing coal industry to support a large coal gasification industry. The future of the gasification industry, however, is dependent on economic factors other than raw-material existence.

COAL GASIFICATION PLANT SITING IN THE SOUTHERN AND WESTERN UNITED STATES

The bulk of Western Interior coal reserves are high sulfur (greater than 1.9 percent for the purposes of this report) and from this standpoint, well suited for use in gasification.

In the western provinces, high-sulfur coal constitutes only a small percentage of the reserve base. This coal has not been considered separately as a source for gasification feedstock.

Most of the problems associated with SNG development in the East (return on capital investment, development-production lag times, Government regulation, etc.) are also common to the western coal industry.

Among the considerations that make western coalfields attractive for SNG development is the availability of abundant reserves of thick, surface-minable deposits (excepting the Western Interior province) from which low-cost coal can be obtained. Much of this coal has not been committed to other uses. Disadvantages of western coal for SNG development include the problems of water availability, remoteness from large existing gas markets, and some opposition to the development.

Most SNG developments currently in the planning or projection stages are in the West; however, some coal reserves in the East have been tentatively allocated for use in gasification pending completion of feasibility and other studies.

Gulf Coast Province

This province comprises Texas, Louisiana, Arkansas, and Alabama. With the exception of Texas, little or no lignite mining is being conducted in these States.

Texas

Available data show only one county, Milam, with sufficient reserves to support a basic SNG plant. The Texas Bureau of Economic Geology has published lignite resource figures (22) that indicate that several additional counties have sufficient potential resources to support gasification development.

Current and projected plans for utilizing Texas lignite are for thermal-electric generation. The potential for the development of a SNG industry, particularly in south Texas, may depend more on the availability of water than on coal supply (22). Preliminary data indicate that Texas coal production in 1976 totaled 14.2 million tons.

Alabama

Marengo County has sufficient lignite reserves for a synthetic gas plant. Available data on Marengo County indicate a lignite with generally high Btu and sulfur content (10).

Because lignite has never been mined commercially in Alabama, more data are required to forecast the feasibility of mining these deposits for gasification plant feedstock.

Western Interior Province

The Western Interior province comprises Arkansas, Iowa, Kansas, Nebraska, Missouri, Oklahoma, and north-central Texas. The coal within the province is predominantly bituminous. A tabulation of the States and counties in the province that are potential gasification locations is shown in the appendix.

Oklahoma

Based on reserve data developed by the Bureau of Mines, only Le Flore County has sufficient coal to support a basic SNG plant. Although much of the reserves are deep, the Oklahoma Geological Survey (19) has determined that a significant part is of coking quality--a use value that should exceed that of SNG feedstock. Several other counties have sufficient potential resources to support basic SNG plants (19).

Most of the Oklahoma reserves are extractable only by underground mining methods; thus any SNG industry in Oklahoma would entail development of an extensive underground mining industry. Relatively thin coalbeds in Oklahoma, as in most of the Western Interior province, would complicate underground mining technology and cost effectiveness.

The Oklahoma Geological Survey's analysis of potential SNG sites shows that, because of the scattered location of the coal, a considerable amount of feedstock for any projected plant would have to be hauled 25 to 50 miles. Oklahoma's 1976 coal production is estimated to total 3.0 million tons.

Kansas

All known Kansas reserves are strippable. Linn County, within 60 miles of Kansas City, has sufficient coal in one bed (Mulberry) for a gasification complex. Within the county (40), the reserves lie in mining districts separated by 6 to 25 miles from each other.

Three other Kansas Counties--Bourbon, Cherokee, and Crawford--have sufficient reserves for gasification; these reserves are in three or more beds. Present production will probably deplete reserves in Cherokee County below the minimum required before a plant could be built. The beds are the Mulky, Bevier, Fleming, Mineral, and Weir-Pittsburg. Various combinations of these beds are probably amenable to multiple-seam mining. Coal production in the State during 1976 is estimated at 732,000 tons.

Missouri

Generally thin, Missouri coalbeds are not competitive with thick-bed coal from Illinois and the Western States. The thinness of the coal requires acquisition of large areas of land to insure adequate reserves.

Many counties have reserves in multiple beds, giving rise to uncertainties as to the feasibility of mining all or most of these beds.

The economics of underground mining in thin beds is presently unattractive. Therefore, counties with underground reserves have been rated at low potential. Advances in technology and depletion of available strip coal could alter this situation. Missouri's 1976 production is estimated at 5.8 million tons.

Three Missouri counties have moderate potential for the development of SNG plants. Macon, Randolph, and Henry Counties have adequate strip and large underground reserves that can probably be developed. Strip reserves in all three counties are in two beds that have been tandem mined. More data are required to determine whether multiple-seam mining is economically feasible for the large quantities of coal required for SNG plants.

Additional strippable reserves are available in Johnson, Bates, and Vernon Counties, augmenting Henry County as a potential site. This county is also near a large metropolitan market. Large underground reserves exist in Mercer and Putnam Counties, an area with future potential.

The Missouri Geological Survey and Water Resources has published extensive resource and reserve data on coals 12+ inches thick (38-39).

Iowa

Because most Iowa coalbeds are lenticular, the lack of continuity of coal of minable thickness decreases the potential for large coal-consuming projects such as SNG plants. Much more data are required to define clearly the extent and potential of Iowa coal. Available data show Polk and Monroe Counties with sufficient underground reserves. However, a significant quantity of Polk County reserves occurs near or beneath the city of Des Moines (26). Problems of land acquisition and the potential for land subsidence make mining of Polk County coal unlikely.

Monroe County, particularly if considered in conjunction with Marion and Mahaska Counties, has ample underground reserves for future SNG development, subject to the lack of continuity previously mentioned. Coal production in Iowa during 1976 is estimated to total 580,000 tons.

Rocky Mountain Province

The Rocky Mountain province includes the western parts of Montana and Wyoming and the coal-bearing areas of Arizona, Colorado, New Mexico, and Utah. The coal within the province is predominantly bituminous and subbituminous

with local occurrences of lignite and anthracite. The largest deposits of strippable coal--70 percent--occur in the broad San Juan Basin in New Mexico and the smaller Black Mesa Basin in Arizona.

New Mexico

San Juan County has large strippable reserves in the Fruitland Formation. Reserves adequate for gasification in the Navajo Fruitland field comprise one to seven beds. Coal varies in quality, thickness, and lateral continuity. Thickness varies from 20 feet to less than 1 foot.

Reserves have been almost totally committed to thermal-electric generation and gasification. In the early 1970's both El Paso Natural Gas Co. and Western Gasification Co. (WESCO) planned 250-MMscfd SNG facilities for northwestern New Mexico. However, the El Paso Natural Gas Co. plans have been temporarily dropped, and currently the WESCO plans are uncertain.

McKinley County has barely adequate strip reserves for a basic SNG plant, with some underground backup. The county has been rated low in potential because part of the strippable reserves has been dedicated to thermal-electric generation.

Although Colfax County has abundant underground reserves for synthetic-gas plants, it has been rated low potential because the coal is largely of coking quality (2), a value which exceeds that of gasification feedstock. Estimates of the State's coal production during 1976 total 9.8 million tons.

Arizona

Reserves in Navajo County are largely committed for use in thermal-electric generation and have, for this reason, been rated low in potential for SNG development. Preliminary data on 1976 Arizona coal production indicate that approximately 10.2 million tons were mined.

Colorado

Twelve counties have sufficient underground reserves and two have enough strip reserves to support SNG plants. Almost without exception, the underground reserves are aggregated in multiple beds. In two counties, reserves are in 40 or more beds. Many beds are lenticular. In some instances, the geology of the coalfields is structurally complex. For the preceding reasons, coupled with the presence in the Rocky Mountains of large reserves of strippable coal, underground potential has been rated low. In addition, the Trinidad field in Las Animas County is largely of coking quality (27), a potential use that rates higher in utilization than as feed for gasification.

Present reserve data indicate two Colorado counties with sufficient strippable coal to support gasification plants. The Yampa coalfield in Routt and Moffat Counties contains strippable coal in several beds (4). Thickness ranges in beds presently being stripped are Wadge, 4.5 to 11 feet, and Lennox, 4 to 7 feet.

Because the reserves are widespread and the beds are only moderately thick, two or more mines certainly will be required to supply the necessary feed for a basic SNG plant. Colorado production for 1976 is estimated at 9.4 million tons.

Utah

Carbon County coal must be extracted by underground mining. Because of mining problems that complicate extraction of these coals (11), the product is relatively high priced. The same difficulties inhibit establishment of the large-tonnage mines necessary to supply synthetic gas plants (annual requirements in excess of 5 million tons). Some reserves are of coking quality. Significant quantities of coal in the county are committed to power generation.

Large underground reserves exist in Garfield County. Present potential for SNG production is low because of the combination of higher costs for underground coal and questions of adequate water supplies.

Kane County, in particular the Alton field (12), has possible potential because strip reserves are available and, in the future, can be supplemented by large underground reserves. The State's 1976 production is estimated to total 7.9 million tons.

Wyoming

Wyoming has coalfields in the Rocky Mountain and Northern Great Plains provinces. Discussion of all Wyoming areas has been included in the Northern Great Plains section.

Northern Great Plains Province

The eastern parts of Montana and Wyoming and the western parts of North and South Dakota lie within the Northern Great Plains province. Subbituminous coal and lignite are the predominant ranks of coal in the province, whereas bituminous coal occurs locally in north-central Montana. Because of abundant strip reserves in this province, only strippable coal has been considered for SNG development in the near future.

The entire Northern Great Plains province is in a unique coal reserve position. Many sites are capable of supporting multiple basic SNG plants, so many, in fact, that the available coal certainly would exceed the available water and capital to support ultimate development of these reserves for synthetic gas manufacture.

Wyoming

Carbon County has been rated as low potential because most reserves are deep and because the structure of the coal formations is often complex. However, large, potential strippable resources (20) may make the county important for future extensive synthetic-gas development in their general vicinity.

Lincoln County has large reserves in multiple beds. Because of complex folding and thrust faulting, strippable reserves occur in long, narrow bands, which would necessitate strippimg over long distances. Deep reserves as a future backup are adequate.

The Great Divide Basin region of Sweetwater and Carbon Counties contains abundant strippable reserves in moderately thick beds (43). Generally flat-lying coalbeds appear amenable for large-scale strip mining.

Wyoming's Powder River Basin contains abundant coal in thick beds; in some places, the thickness of single or merged beds exceeds 100 feet. Campbell County has the highest potential coal reserves in the Western United States for SNG development. The Wyodak zone in Campbell County comprises a single bed with a thickness of 100 feet or in other minable multiple beds. In the latter case, individual bed thicknesses range from 5 to 50 feet, with partings of 4 to 70 feet. Wide areas with large single beds or multiple beds with favorable mining characteristics extend from Gillette in Campbell County to Antelope Creek in northern Converse County. The Spotted Horse area in northern Campbell County has ample reserves to support a multiple basic plant complex. In Johnson County, the Buffalo field (particularly the Healy deposit) has large reserves located near an available potential water source. Sheridan County, in the Powder River Basin, mostly has deep reserves. A complex served by coal from Sheridan and Big Horn Counties, Mont., may be feasible, however. Preliminary estimates of 1976 Wyoming coal production total 30.9 million tons.

Montana

The Northern Great Plains region of Montana has abundant reserves in relatively thick beds (average for bituminous is 28 feet; for lignite, 24 feet) (44). The State's coal production reached an estimated 26.1 million tons in 1976.

The following is a compilation of coalfields that would support large multiple basic plant complexes. Generally, these fields have reserves in thick single beds, beds mutually minable, or reserves in different beds concentrated in a limited area. Numerous other fields in the State could support one or two synthetic gas plants. Details on most of the fields listed are available in Montana Bureau of Mines and Geology Bulletin 91 (32).

County	Field
Rosebud.....	Colstrip, Cheyenne Meadows, Canyon Creek.
Powder River..	West Moorhead, Pumpkin Creek, Foster Creek (also in Custer County).
Big Horn.....	Decker, Kirby, Hanging Woman Creek (also in Rosebud and Powder River County), Sarpy Creek, Wolf Mountains.

In addition, the Lane, Carroll, and Redwater River lignite fields in Richland, Dawson, and McCone Counties and the Wibaux-Beach, North Dakota, lignite field may be worthy of further evaluation.

Large coal reserves are in the Ashland, Otter Creek, Yager, and Poker Jim Lookout fields (Powder River and Rosebud Counties) lying within the Custer National Forest. This coal may be withdrawn from mining should a Federal surface-mining law be enacted.

North Dakota

The State's reserves are lignite, with individual beds ranging up to 25 feet thick (44). Economic overburden limits vary; some areas have multiple beds that may be mutually mined (35).

North Dakota lignite has been proposed for development for synthetic-gas production. Counties with reserves committed to gasification are Bowman, Dunn, McLean, Mercer, Oliver, Slope, and Stark. One group with adequate coal reserves under ownership or lease has obtained rights for 17,000 acre-feet of water from Lake Sakakawea.

A basic plant will require up to 11.5 MMtpy of lignite. This feed will be supplied by two or more separate mines.

Four counties, Hettinger, McKenzie, Ward, and Williams, have reserves for one or two plants but are not near the areas proposed for SNG development by industry groups. Billings County has enough coal for one or two plants; these reserves are adjacent to larger reserves in Dunn and Stark Counties. Estimated 1976 lignite production totaled 11.2 million tons.

Pacific Coast Province

California, Nevada, Oregon, and Washington comprise the Pacific Coast province.

Only the subbituminous deposit in Lewis and Thurston Counties, Wash., contains enough reserves to support a coal gasification plant. This deposit, now being mined for thermal-electric generation, contains only enough strippable reserves for one basic coal gasification plant; underground reserves would support only one additional plant. The extent of commitment to thermal-electric use is unknown. Washington production during 1976 is estimated at 4.1 million tons.

Alaska

Geographically, the Alaskan coal areas can be divided into the Northern Alaska fields (north of the Brooks Range), the Interior region, and the Coastal region (south of the Alaska Range). Alaskan coals range from lignite to anthracite. Present data indicate large strippable reserves in the Northern Alaska field. The Nenana field has strippable reserves sufficient for one basic unit.

Most of Alaska's coalfields have not been thoroughly investigated; thus, extensive additional reserves may be proven by further investigation. Pending further evaluation, resource figures (3) indicate that the Susitna and Kenai fields may also have adequate to abundant reserves for gasification.

Alaska's present and potential natural gas production, the remote location of many of the coalfields from transportation and population centers, and the appreciable additional expense of equipment and construction combine to negate the feasibility of SNG complexes in the near future. Estimates of 1976 coal production in Alaska totaled 706,000 tons.

WATER AVAILABILITY

Figure 4 shows the U.S. water resource regions; superimposed on these regions are the principal coalfields. The U.S. Geological Survey has summarized the general water situation in the United States (34). Data condensed from this report appear in table 5.

TABLE 5. - Water-supply data of selected water resource regions of the United States

(Million acre-feet per year)

Regions	Streamflow (average runoff)	Estimated dependable supply[1] --1980	Withdrawals 1970
Ohio	140.0	53.7	40.3
Tennessee	45.9	15.7	8.8
South Atlantic-Gulf	220.6	84.0	39.2
Arkansas-White-Red	81.8	22.4	13.4
Missouri	60.5	33.6	26.9
Texas-Gulf	35.8	19.0	23.5
Upper Colorado	14.6	14.6	9.1
Lower Colorado	3.6	2.2	8.1
Columbia-North Pacific	235.0	78.5	33.6

[1] Estimated dependable supply--that part of average annual runoff available on a dependable basis--generally the minimum monthly supply including ground water and water released from reservoirs at points of principal use. (Woodward, D. R. Availability of Water in the United States, with special reference to industrial needs by 1980. Armed Forces Indus. Coll., Washington, D.C., 1957, p. 73.)

Source: Estimate of water in the United States, 1970. U.S. Geol. Survey.

Water withdrawals are low compared with streamflow in the Ohio, Tennessee, South Atlantic-Gulf, Arkansas-White-Red, and Columbia-North Pacific regions--indicating a continuing dependability of supply.

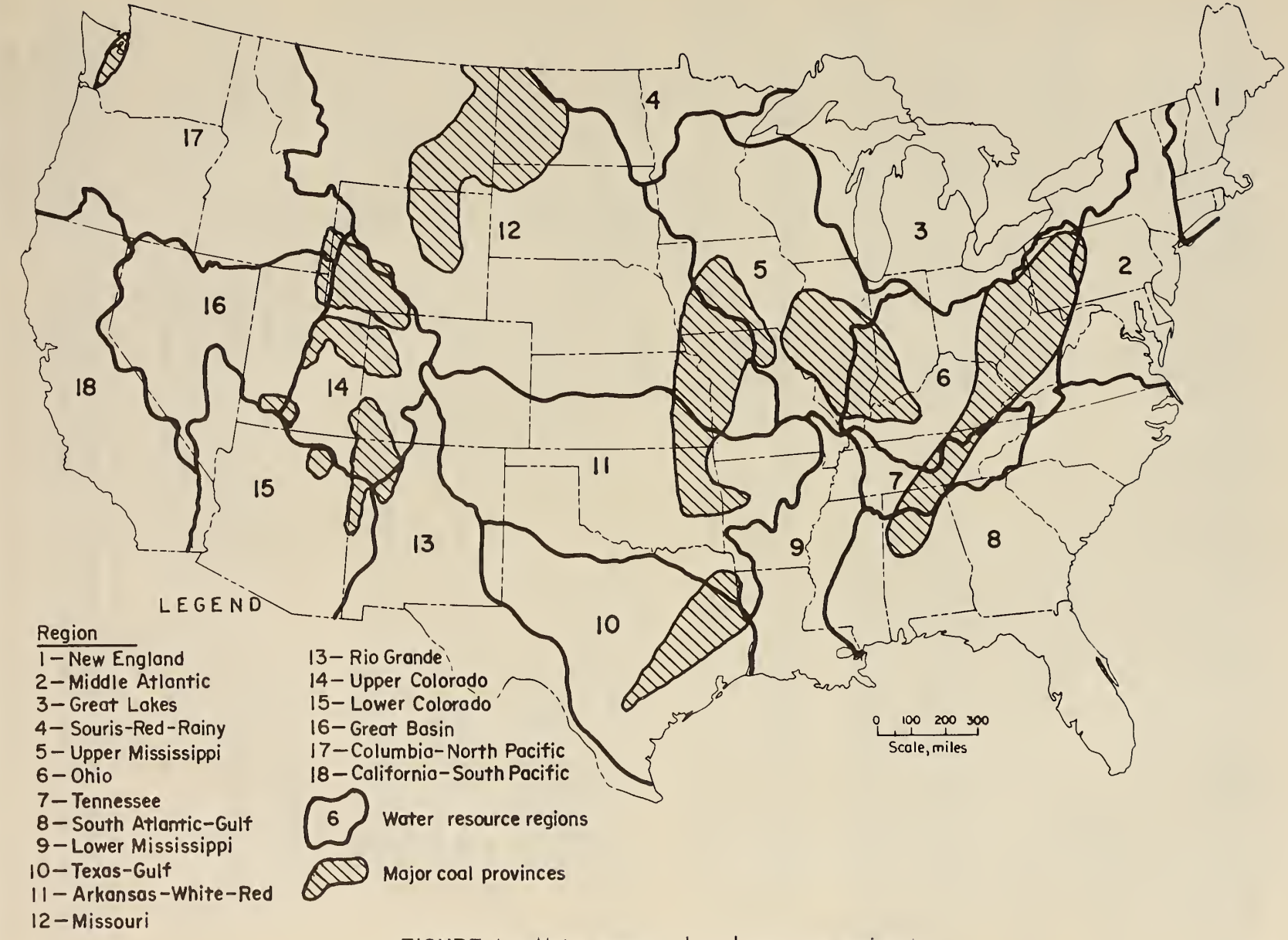

FIGURE 4. - Major water and coal resource regions.

The Missouri and Upper Colorado regions have a moderately favorable estimated dependable supply versus withdrawal ratio. However, the Missouri and Upper Colorado, as well as the Texas-Gulf and Lower Colorado regions, have periodic water shortages. Withdrawals exceed estimated dependable supply in the Texas-Gulf and Lower Colorado regions. This natural shortfall has been counteracted by the extensive use of ground water and reservoir development.

In summary, the water potentially available for extensive gasification development is low in the Texas-Gulf and Lower Colorado, moderate in the Missouri and Upper Colorado, and good in the remaining water resource regions.

The Upper Colorado and Western Missouri water resource regions are presently slated for the first gasification complexes in the United States. The Department of the Interior has assembled water resource data (47) that include those States (excepting North Dakota) in these regions where the development of the SNG industry seems to have the highest potential. Table 6 is a summary of data from this study.

TABLE 6. - Estimated 1975 surface-water situation in selected States

(Thousand acre-feet)

State or region	Supply	Estimated legal and instream flow commitments	Net water supply
New Mexico:			
Upper Colorado	1,751	1,582	169
Lower Colorado	211	177	34
Utah:			
Upper Colorado	11,279	10,730	549
Lower Colorado	178	0	178
Colorado:			
Missouri	347	642	205
Upper Colorado	8,446	6,869	1,577
Wyoming:			
Missouri	7,169	4,230	2,939
Upper Colorado	1,686	1,059	627
Montana: Missouri	16,866	0	16,866

Source: U.S. Dept. of Interior, Westwide Study Report on the Critical Water Problems Facing the Eleven Western States.

Net water supply shown in table 6 should not be assumed as available in its entirety. Channel flow must be maintained; such alternate uses for fish, wildlife, and recreation must be considered when water is allocated. Generally the quantity of water to be allocated to these alternate uses, subject to political considerations, has yet to be determined. In addition, sites

at which water is available may be distant from point of intended use, giving rise to economic obstacles (that is, reservoir development, pipeline costs, etc.). The Westwide Study developed conclusions on the availability of water in the States listed on table 6.

In New Mexico, SNG development will take place in the San Juan region (Upper Colorado water resource region). Available water in this area has been committed to presently active or authorized projects (47, p. 343), including gasification.

Available coal reserve data show that northwestern Colorado has the best present potential for gasification in the State. Water is available in this area (47, p. 270). However, thermal-electric and oil shale development occurring or planned in this same area will compete for water allocations.

Utah also has some additional water available for use (47, p. 380). Thermal-electric and oil shale development, as well as nonenergy uses, will compete heavily for Utah's remaining allocatable water.

In Wyoming, the area of highest potential for gasification development is the Powder River basin, where local water supplies are short. Therefore, although Wyoming has allocatable water (5), diversion from other sources into the Powder River basin area will be necessary for extensive gasification development (47, p. 418).

The U.S. Bureau of Reclamation issued a report on potential reservoir and pipeline-diversion projects in part of the Powder River basin (46). The most feasible reservoirs and pipeline locations are ultimately dependent upon the location and design of the consumptive units. Any such diversion projects should entail coordination between Montana and Wyoming energy development because most of the water available in the region has been apportioned between the two States. Proper siting of pipelines could aid energy development in both States. Future water supplies could be developed by construction of reservoirs on the Powder, Tongue, Shoshone, and possibly Yellowstone Rivers. The Great Divide Basin field occurs partly within the Upper Colorado water resource region. Wyoming has allocatable water from the Green River (47, p. 418), a part of which might be diverted to the Great Divide Basin for gasification development.

Water is available for gasification development in Montana (47, p. 308). Development of the prime area, southeast Montana, will require diversion from the Yellowstone-Missouri River systems and could be part of the same storage-diversion systems that would supply northeast Wyoming development. All of the available Montana water was under contract (option) for industrial use at the time of issuance of the Bureau of Reclamation Aqueduct study. No specific use has been put on most of this water by those with contract rights.

Water for northeast Montana lignite development can probably be supplied without construction of additional storage, although diversion facilities would be required (47, p. 308).

Estimates are scanty as to the amount of water available for industrial use in North Dakota. Natural runoff in the lignite region of the State is relatively low (3.21 million acre-feet per year); annual flow exceeded in 90 percent of the years is 0.75 million acre-feet per year (34), indicating that the area is susceptible to drought and water shortages. However, North Dakota is entitled to Missouri River flow; the river has been subject to reservoir development (Garrison Dam) near much of the potential coal development.

Most of the Western Interior coal province occurs within the easterly parts of the Arkansas-White-Red and Missouri water resource regions. Runoff generally far exceeds water use in the coal areas of these regions. However, runoff in 90 percent of the years falls short of present demand in the Canadian and Kansas River subregions (34), indicating the possibility of periodic water shortages in these particular drainages. Water supply seems to be sufficient for any modest gasification development that might take place in the Western Interior.

In the coal regions east of the Mississippi River, available water for industrial expansion, including gasification development, appears adequate for the near future. The development of capacity to store excess flows and facilities to deliver water to the right place at the right time are major water-related problems in these areas.

Detailed listings of streamflow in all of the coal regions have not been included because the question of water allocation, rather than physical flow, will be the main concern in most of the potential SNG areas.

CONCLUSIONS

The counties listed in the appendix were chosen strictly on the basis of comparing reserves to the coal requirements for a 35-year-life basic SNG complex (previously defined as the minimum unit economically justifiable).

Obviously, many criteria other than reserves and Btu content should be considered when a specific SNG site is selected. Factors such as ownership, availability and commitments, bed thickness, number of beds constituting the reserves, and feasibility of underground and strip mining are critical factors.

The Bureau of Mines does not have adequate information on coal ownership or to what purpose owned or leased coal has been committed. Many counties, particularly in the Eastern United States, have adequate physical reserves but are not attractive because of differing ownership of blocks or beds. Often these blocks have been committed to alternate uses.

Some counties have adequate reserves but relatively thin beds. Mining adequate tonnages to supply synthetic-gas plants in such conditions, either by underground or surface methods, entails acquisition and use of large land areas. In the Western Interior province, for example, rough estimates indicate 10 to 20 percent of some counties would be mined/undermined to supply the necessary amounts of coal.

Although total reserves may be adequate in a given county or area, they may be scattered among several townships or located in multiple beds. Assessing the potential of such reserves, then, becomes a complex study of transportation costs, feasibility of multiple-bed mining, and capital-investment requirements (for multiple mine sites).

As to multiple-bed reserves, the underground mining of one bed may prohibit or make questionable the mining of beds stratigraphically positioned higher or lower. What is practical in such conditions generally remains to be determined, or awaits the development of technology applicable to such situations.

Although some counties may be unattractive as potential plant sites because of bed thickness, scattered location of reserves, underground versus surface-mining potential, etc., they may, in fact, be good locations because of the nearness of markets or existing transmission lines. Determination of relative potential in this case involves detailed studies of present and future market demands, potential local natural gas scarcity, and pipeline-transmission costs.

In some counties, coal reserves are available in such enormous quantities that predicting the numbers of plants based only on coal availability is inadvisable. Capital investments and water requirements in such cases exceed reality.

For these reasons, this study has not attempted to pinpoint specific SNG plantsites or to suggest that plants should be located within all the counties discussed in the text or listed in the appendix. It is possible, however, to delineate several areas that have especially good potential for the development of gasification complexes.

The majority of presently planned or projected SNG developments propose ultimate expansion to 1,000 MMscfd (8) or four times the basic SNG capacity. Using this figure as a base, it is possible to outline the eight areas listed in table 7 and shown on figure 5. Within these areas, each of the contiguous counties has adequate reserves to support a plant or plants of this size. The eight-unit areas each have vastly greater reserves than would be required by a 1,000-MMscfd complex.

TABLE 7. - Areas of high potential for gasification development

Area number	State and county	Type of reserve base
1	Ohio (Jefferson, Harrison, Belmont) Pennsylvania (Washington, Greene) West Virginia (Marshall, Marion, Monongalia)	Deep.
2	Kentucky (Hopkins, Muhlenberg, Webster, Union, Henderson) Illinois (Hamilton, Williamson, Saline, Gallatin)	Strip-deep.
3	Illinois (St. Clair, Washington, Perry, Madison, Sangamon, Christian, Macoupin, Montgomery, Bond)	Deep-strip.
4	Illinois (Vermilion, Edgar)	Strip-deep.
5	Illinois (Knox, Fulton, Peoria)	Strip.
6	New Mexico (San Juan)	Do.
7	Montana (Big Horn, Rosebud, Powder River, Custer) Wyoming (Campbell, Johnson)	Do.
8	North Dakota (Dunn, Mercer)	Do.

Thus, despite the complex of factors involved in picking particular sites, SNG plants located within these areas should be in viable coal supply positions.

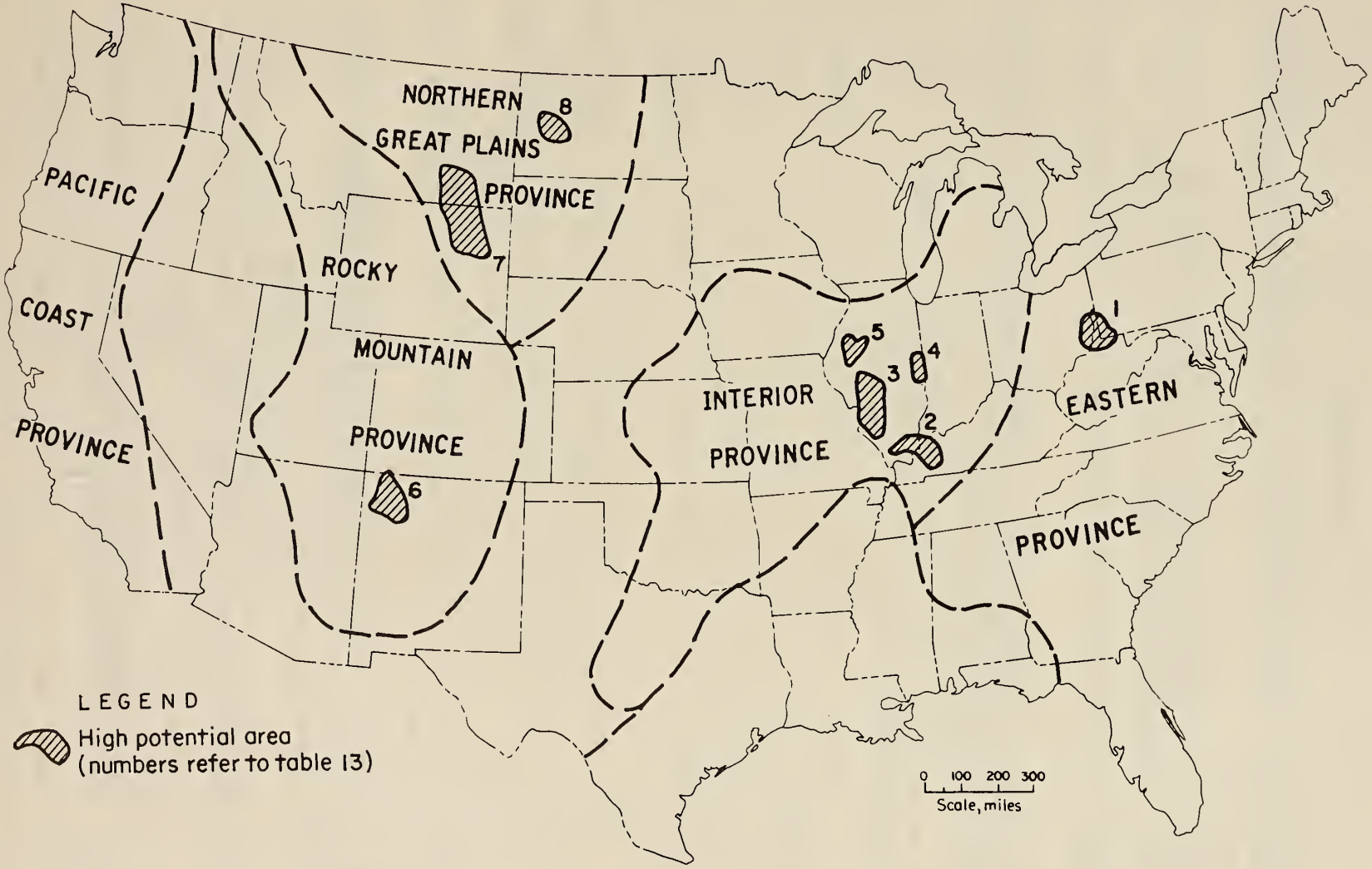

FIGURE 5. - Areas of high potential for gasification development.

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APPENDIX.--SUMMARY OF COUNTIES WITH POTENTIAL FOR GASIFICATION DEVELOPMENT

State and county	Average Btu (as received)	Reserves,[1] million tons		Number of beds[2]
		Deep	Strip	
Alaska:				
Barrow division	10,910	1,329	-	Beds uncorrelated.
Northern Alaska	10,910	-	4,499	Beds uncorrelated.
Seward Peninsula	11,310	1,082	485	Beds uncorrelated.
Arizona: Navajo	10,260	-	250	Beds uncorrelated.
Colorado:				
Garfield	12,130	315.20	-	19
Gunnison	12,690	397.04	-	18
La Plata	13,120	183.57	-	2
Jackson (subbituminous)	10,120	469.40	-	8
Las Animas	12,650	474.21	-	49
Moffat:				
Bituminous	11,500	1,137.00	229.50	47
Subbituminous	-	328.20	-	8
Ouray	10,140	434.68	-	-
Rio Blanco	11,210	608.40	-	70
Routt:				
Bituminous	11,590	1,561.06	351.05	19
Subbituminous	-	384.85	-	8
Weld (subbituminous)	9,810	264.66	-	7
Illinois:[3]				
Bond	10,780	1,043.93	-	2
Bureau	10,600	586.78	-	3
Christian	10,600	1,908.41	-	5
Clinton	10,880	753.80	-	2
Crawford	11,260	252.29	-	5
Douglas	11,560	234.66	-	3
Edgar	11,480	997.44	-	4
Fayette	11,260	669.02	-	2
Franklin	11,890	582.96	-	5
Fulton	10,790	-	1,511.27	5
Gallatin	12,590	1,003.67	-	5
Greene	10,890	-	359.73	2
Grundy	11,150	-	381.01	2
Hamilton	11,260	1,390.89	-	2
Henry	10,330	-	323.87	4
Jackson	11,830	-	240.52	4
Jefferson	11,800	493.49	-	2
Knox	10,730	-	514.28	3
La Salle	11,040	617.29	-	3
Lawrence	11,260	509.37	-	6

See footnotes at end of table.

State and county	Average Btu (as received)	Reserves,[1] million tons		Number of beds[2]
		Deep	Strip	
Illinois[3]--Continued				
Livingston	10,910	331.20	-	3
Logan	10,680	463.80	-	1
McLean	11,240	239.94	-	3
Macon	10,770	250.41	-	2
Macoupin	10,650	1,950.04	-	7
Madison	10,760	778.88	432.84	2D, 2S
Marion	11,100	239.97	-	2
Menard	10,740	832.20	-	1
Montgomery	10,660	2,226.79	-	7
Peoria	10,540	-	1,208.89	4
Perry	11,240	647.18	783.43	2D, 2S
Putnam	11,260	335.67	-	3
Randolph	10,980	-	354.61	2
St. Clair	11,030	542.27	988.34	2D, 1S
Saline	12,370	1,384.84	354.69	7D, 5S
Sangamon	10,490	2,017.82	-	4
Shelby	9,820	406.11	-	3
Vermilion	10,930	847.52	287.95	3D, 2S
Washington	10,910	886.47	-	2
White	11,930	565.71	-	4
Williamson	11,940	755.69	309.58	8D, 6S
Indiana:[3]				
Gibson	11,550	734.33	-	3
Knox	11,200	735.30	-	4
Posey	11,510	410.91	-	4
Sullivan	11,400	779.93	-	5
Vanderburgh	11,090	257.28	-	3
Vermillion	11,330	222.79	-	5
Vigo	11,020	576.08	-	7
Warrick	11,450	286.00	252.10	5D, 4S
Iowa:				
Monroe	10,290	295.64	-	4
Polk	9,440	280.65	-	6
Kansas:				
Bourbon	-	-	218.80	3
Cherokee	12,640	-	200.85	5
Crawford	11,990	-	255.50	6
Linn	11,380	-	403.30	1
Kentucky, eastern:[3] Pike	13,450	258.50	-	17
Kentucky, western:[3]				
Henderson	11,120	857.06	425.81	4D, 4S
Hopkins	12,190	1,029.23	651.75	9D, 10S
McLean	11,700	412.48	-	3
Muhlenberg	11,890	511.99	926.65	7D, 9S
Ohio	12,030	-	474.77	8
Union	12,650	1,097.99	-	7
Webster	12,570	818.77	-	5

See footnotes at end of table.

State and county	Average Btu (as received)	Reserves,[1] million tons		Number of beds[2]
		Deep	Strip	
Missouri:				
Adair	10,030	274.88	28.22	2
Audrain	10,500	267.74	67.26	1
Bates	11,380	166.59	127.50	4
Henry	11,920	74.24	421.22	5
Johnson	11,020	38.50	331.18	5
Linn	10,770	321.87	-	2
Macon	10,650	211.16	231.56	3
Mercer	10,500	335.90	-	(?)
Putnam	9,910	219.30	75.46	1D, 2S
Randolph	11,380	382.10	200.72	1D, 2S
Vernon	12,200	38.40	245.31	2D, 5S
Montana:				
Big Horn (subbituminous)	9,480	17,200	6,975	Beds uncorrelated.
Custer:				
Subbituminous	7,470	419	1,515	Beds uncorrelated.
Lignite	7,470	-	356	Beds uncorrelated.
Dawson (lignite)	7,120	-	1,020	Beds uncorrelated.
McCone (lignite)	7,600	-	970	Beds uncorrelated.
Musselshell (subbituminous)	10,660	1,913	-	Beds uncorrelated.
Powder River:				
Subbituminous	7,730	10,180	7,425	Beds uncorrelated.
Lignite	7,730	-	1,300	Beds uncorrelated.
Richland (lignite)	7,250	-	765	Beds uncorrelated.
Rosebud (subbituminous)	8,820	11,780	4,775	Beds uncorrelated.
Sheridan (lignite)	6,350	-	386	Beds uncorrelated.
Treasure (subbituminous)	8,580	585	238	Beds uncorrelated.
Wibaux (lignite)	6,100	-	775	Beds uncorrelated.
Yellowstone (subbituminous)	8,890	336	-	Beds uncorrelated.

See footnotes at end of table.

State and county	Average Btu (as received)	Reserves,[1] million tons		Number of beds[2]
		Deep	Strip	
New Mexico:				
McKinley (bituminous and subbituminous).....	11,310	65	213	Beds uncorrelated.
Colfax (bituminous).....	12,560	787	-	Beds uncorrelated.
San Juan (subbituminous)..	11,620	-	1,707	Beds uncorrelated.
North Dakota (lignite):				
Billings.....	6,350	-	862	Beds uncorrelated.
Bowman.....	6,120	-	667	Beds uncorrelated.
Dunn.....	6,310	-	1,700	Beds uncorrelated.
Hettinger.....	6,340	-	833	Beds uncorrelated.
McKenzie.....	6,330	-	701	Beds uncorrelated.
McLean.....	6,620	-	858	Beds uncorrelated.
Mercer.....	7,200	-	1,688	Beds uncorrelated.
Oliver.....	6,410	-	535	Beds uncorrelated.
Slope.....	5,950	-	1,977	Beds uncorrelated.
Stark.....	6,150	-	1,084	Beds uncorrelated.
Ward.....	6,790	-	426	Beds uncorrelated.
Williams.....	6,420	-	961	Beds uncorrelated.
Ohio:[3]			-	
Athens.....	11,610	357.48	-	4
Belmont.....	12,500	2,227.34	246.50	5D, 2S
Carroll.....	12,270	410.97	-	5
Columbiana.....	12,610	387.26	-	4
Guernsey.....	12,020	648.23	-	5
Harrison.....	12,590	865.69	-	6
Jefferson.....	12,650	729.34	253.68	6D, 6S
Lawrence.....	11,110	255.48	-	5
Meigs.....	11,550	218.40	-	3
Monroe.....	11,690	266.97	-	3
Morgan.....	11,910	248.02	-	4
Muskingum.....	11,730	410.84	-	6
Noble.....	12,060	324.91	291.58	4D, 3S

See footnotes at end of table.

State and county	Average Btu (as received)	Reserves,[1] million tons		Number of beds[2]
		Deep	Strip	
Ohio:[3]--Continued				
Perry	11,580	326.89	-	3
Stark	12,100	214.67	-	4
Tuscarawas	11,820	479.48	232.81	5D, 5S
Oklahoma: Le Flore	13,790	158.5	40.0	-
Pennsylvania:[3]				
Armstrong	13,110	541.19	-	5
Butler	12,800	382.70	-	8
Cambria	13,620	382.44	-	6
Clarion	12,850	339.51	-	6
Clearfield	13,220	365.40	-	7
Fayette	13,210	439.70	-	9
Greene	13,160	3,029.66	-	4
Indiana	13,460	562.89	-	7
Somerset	13,360	418.92	-	10
Washington	12,840	1,434.87	-	5
Westmoreland	13,290	316.45	-	8
Texas: Milam (lignite)	8,070	-	355.64	Beds uncorrelated.
Utah:				
Carbon (bituminous)	12,760	437	-	Beds uncorrelated.
Garfield (bituminous)	9,680	576	20	8
Kane (bituminous)	9,700	976	170	11
Washington: Lewis	8,060	602	340	7
West Virginia:[3]				
Barbour	13,260	539.43	-	9
Boone	13,380	226.22	-	5
Harrison	13,460	209.71	-	4
Lewis	12,960	358.61	-	6
Logan	13,450	217.86	-	6
Marion	13,590	1,089.02	-	8
Marshall	12,900	1,734.95	-	4
Monongalia	13,220	1,490.91	-	8
Ohio	12,760	216.06	-	5
Preston	13,330	332.48	-	9
Taylor	13,130	295.93	-	3
Upshur	13,250	316.42	-	11
Webster	13,930	203.91	-	9
Wetzel	12,650	482.27	-	5

See footnotes at end of table.

State and county	Average Btu (as received)	Reserves,[1] million tons		Number of beds[2]
		Deep	Strip	
Wyoming:				
Campbell	8,000	8,182	14,572	11
Carbon	9,000	1,143	151	1
Converse	8,450	467	694	Beds uncorrelated.
Johnson	7,940	756	1,700	10
Lincoln	9,000	-	850	Beds uncorrelated.
Sheridan	9,650	2,929	122	17
Sweetwater	9,000	202	836	1

[1] Based upon recovery rates of 57 percent for deep minable coal and 85 percent for surface minable coal from the demonstrated coal reserve base.
[2] D = deep, S = strip.
[3] Reserves includes coal with a sulfur content of 1.9 percent or greater only.

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